COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:              )
                               )
Implementation of Renewables   )
Portfolio Standard Legislation )
(Public Utilities Code Sections) Docket No.
381, 383.5, 399.11 through     ) 03-RPS-1078
399.15, and 445; (SB-1038),    )
(SB-1078)                      )
                               )
and                            )
                               )
Implementation of Renewables   )
Investment Plan Legislation    ) Docket No.
(Public Utilities Code sections) 02-REN-1038
381, 383.5 and 445 (SB-1038)   )
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CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

SACRAMENTO, CALIFORNIA

FRIDAY, FEBRUARY 20, 2004

1:11 P.M.

Reported by:
Peter Petty
Contract No. 150-01-005

COMMISSIONERS PRESENT

John L. Geesman, Presiding Member

James Boyd, Associate Member

ADVISERS PRESENT

Melissa Jones, Adviser to Presiding Member Geesman

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George Simons
PIER Program Manager: Renewables

David Hawkins
California Independent System Operator

Michael R. Milligan
National Renewable Energy Laboratory

Brendan J. Kirby
Oakridge National Laboratory

Kevin Jackson
Dynamic Design Engineering, Inc.
California Wind Energy Collaborative

ALSO PRESENT

Don Smith, Regulatory Analyst
Office of Ratepayer Advocates
California Public Utilities Commission

Nancy Rader, Executive Director
California Wind Energy Association

Thomas Tanton, Principal
T2 & Associates
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Northern California Power Agency

ALSO PRESENT

Robert L. Sims, Sr. Vice President
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Gary L. Allen, Manager
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Edward P. Kahn, Managing Principal
Analysis Group
on behalf of Southern California Edison Company

Sara Steck Myers, Attorney

Mark J. Skowronski, California Business Development
Solargenix Energy (formerly Duke Solar Energy)

Steven Kelly, Policy Director
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Mauri Miller
California Wind Energy Association

Philip Rudnick
Rudnick Realty - Jawbone Energy

Jingehao Mi
California Department of Water Resources

I N D E X

P R O C E E D I N G S

1:11 p.m.

PRESIDING MEMBER GEESMAN: This is a workshop of the Commission's Renewables Committee. I'm John Geesman, the Presiding Member of the Committee. With me is Commissioner Jim Boyd, Associate Member of the Committee. To my right is Melissa Jones, my Staff Adviser.

This workshop is to review the California renewable portfolio standard renewable generation integration cost analysis report. Phase one of the report was published December 10, 2003. I want to thank the folks that have helped assemble this report, particularly at the ISO, Dave Hawkins and Yuri Makarov; at NREL, Michael Milligan; and from Oakridge, Brendan Kirby. All took time out of their schedules to be here today.

I'd like to try and keep the process as informal as possible. We'll go in order with a brief presentation first from our staff. Then we'll go through the report at a fairly general level. And then I'll invite comments. And we'll go one at a time in terms of comments.

I don't think there's anyone here from

the Public Adviser's Office to collect blue cards, so I'll simply respond to raised hands. I know Southern California Edison has requested an opportunity to present some materials, and we'll take them after the presentation of the report. And then we'll simply go one by one.

I don't think we're under any particular time limit to get out of here, so I want to make certain that people have a chance to offer whatever comments or contributions they have to make on the report.

With that, George, do you want to lead off?

MR. SIMONS: Again, this is the phase one findings. There are three phases involved in this report. Phase one really covers the first year results, the years 2002 that the ISO and the team picked. And by the way, I also want to build off of what Commissioner Geesman said and thank the California Wind Energy Collaborative for their assistance in this. We had this work done largely through their efforts.

But we did pick the year 2002 as the year to look at. We're looking again at -- there was quite a bit of data that was collected for that entire year. Phase one looks at capacity credit, load following and regulation. And, again, we're really just looking at integration costs, we're not looking at any of the transmission interconnect costs or the remarketing costs.

The methods group, again, we've already talked a little bit about. I want to talk about the timeline for phase one, phase two and phase three. We actually started this work back in April of 2003. There was a workshop earlier in 2003 to talk about the general methodologies. We received input at that time. We were looking at two methodologies. They consolidated that down to one methodology. We came up with a workshop in September presenting some of the preliminary data, and then came out with a draft report in October and a relatively complete report in December.

Phase two, one of the things we'd like to do is expand out beyond the year 2002; look at additional years. Look at how we would simplify the analysis for capacity credit, and also begin looking at what kinds of secondary effects are associated with the load following; look at what would the impacts be on changes in reserve margin. Also begin looking at other types of impacts on geographical as well as meteorological data on some of the analyses and on the results.

We're focusing in on primarily geothermal and wind in large part because of the renewable resources development report findings that says that given the immense amount of resources available in those two areas, and also the economics and practical technical advances, we anticipate a lot of growth in geothermal and wind with respect to the RPS.

By the way, the phase two results we anticipate coming out with in a March/April timeframe.

Phase three. We will finalize all of these results. We'll have the multiple year analyses. We intend to come out with a methodology that we think will be useful for procurement processes on an ongoing basis. Obviously these methodologies will have to be applied year after year. And be very focused on California-specific information. We anticipate having phase three done by June of this year.

And with that I want to go ahead and get this started and bring up Dave Hawkins from the ISO to talk a little bit about the data that was pulled together for this analysis.

MR. HAWKINS: Putting together the data for this modeling study and analysis proved to be a very interesting challenge because of the massive quantity of data. Like every file we seemed to touch ballooned to at least a 15 megabyte file for a particular day. And, of course, if you're trying to study all the days and all the different facilities, you can easily see where your computer files get -- your disk is pretty full pretty fast as you go through these studies.

What we were looked at is, of course, 2002, as George said, and looking at all of the one-minute generation data and all of the system data. Our system basically collects about 165,000 data points every four seconds. And we can therefore -- and then this is put into a system called PI, which we then use as the extraction of the data.

So we're looking at one-minute generation data, and then ten-minute supplemental energy market data. The ten-minute supplemental market then is basically a redispatch of the system every ten minutes to either move some generation up or move the generation down. And its primary purpose is to follow the load up and down during the day.

Also, as we do the supplemental energy dispatches it actually changes the market clearing price every ten minutes for the real time and balanced energy market.

So then the next piece, of course, is all the hourly load data and the regulation market data that we put in.

So, as I mentioned, we were using both our internal databases at the ISO and then also public data that we put up on websites or other sites that are available. If you hit our website, which is www.caiso.com, go into the oasis area on that particular website, you should be able to extract an incredible amount of information about prices and regulation up, regulation down, and different types of prices and bids on the various systems.

One of the major issues we had was that no only do we do all the extraction of data in individual units, we still have to honor the confidentiality requirements which means that even for the study team we were required to aggregate data together so that you would lump together two to three to four to five plants, hopefully with somewhat similar characteristics, so you would see a large generation facility as part of the study whose specific identity was lost, and hopefully not identifiable as a Southern California Edison-specific plant, or whatever owner-type plant.

So the goal was to make at least a lumpiness to disguise the identity of units, and yet have enough granularity of the data such that we could, the study team could conform the overall analysis.

Finally, no computer system is perfect, and there are things that go wrong in terms of data transmission, drops of data, pieces that get missing, computer files that -- or computer systems that reboot or get missing a piece of data, so there always are things that we have to look for such as data dropouts or something where a transducer got stuck and sent the wrong piece of data for awhile. So it also requires you to do a visual inspection or at least some type of filtering to make sure that you've filtered out some weirdos and anomalies in the data. So all of this, of course, takes a number of months worth of work to try to assemble these kinds of data sets.

As I mentioned, we have what's called the PI system or a process information system. And the advantage of this system is that I can, by typing in various commands into an Excel spreadsheet, go back and access this huge historical database and extract large quantities of data. The good news is you can get at it. The bad news is sometimes these extraction processes will sit there and grind for a couple hours. And we also can find that we can reach the limit of what Excel spreadsheets can hold fairly quickly as we can populate these things.

That also means that we run through several processes where after we've populated these large Excel spreadsheets then we have to literally copy them over again into ASCII-like files where we break the linkages back to the databases that we actually extracted them from so that all these linkages are broken so I can then pass it on to the study team for their particular analysis without having to be connected to the database. So, again, the processing takes a bit of time to pull those things together.

So, for looking at some of the data that we end up with, like a half a million datapoints for looking at just the one-minute data alone. So we were looking at total system load, total system generation. The changes in the frequency between the actual and the scheduled are ACE and area interchange type numbers, what dynamically is brought into the system. And then some of the deviations that we have by regulations or units from their preferred operating points or POPs.

We had also modeling of conventional generators of various types including both hydro and steam plants. And you model how they respond during the year. And because what you're trying to do is say here's what a regular plant does; here's what your load is doing. And then somewhere in there is also what the wind generation and the solar is doing. And you're trying to decompose the responses of all these different types of things and say this is what the response was, or the impact of wind generation, for example, on these other -- the things that are happening in terms of the overall system.

And, of course, the renewable generation we were looking at was the biomass, geothermal, solar and wind, as the particular areas.

The automatic control system or AGC control system that we have, what it basically does is it follows all the four-second or one-minute deviations of the system and it basically looks at all the tieline interchange numbers that we have that comes in from our particular control area, and then calculates what that error is.

And whatever the error is between the difference between running at 60 hertz and your scheduled interchange, that error then gets corrected by an automatic control system that sends signals out to units that are on what are called AGC control. And that literally moves these units up and down and fills in the missing points on the system. So this is part of -- and so part of what we're looking at then, with the renewables, is do the renewables, what part of that overall regulation requirement do the renewables contribute to how much capacity we have to buy in terms of the overall regulation market.

We also have our dispatchers who are doing what essentially is called load following. So as the load picks up from 7:00 in the morning to 7:30 to 8:00, what the generation dispatcher is doing is he's anticipating 10 to 15 to 20 minutes ahead where the load is going, what the blocks of energy are that are scheduled into our control area. And then basically he's doing the supplemental energy dispatch. So he would do a dispatch to George's generator, then, that says, I want you to move from 100 megawatts up to 125 megawatts in the next ten minutes. And he's anticipating how much that load will grow in the next ten minutes. And then that unit then will ramp to the next operating level.

So we have this dispatchable generation that's moving up and down tracking the load which is done by this what is called the automated dispatch system, but it's by commands from the dispatcher, itself, versus the AGC system which does the smaller one-minute and four-second type load following, or regulation.

So you look at various units then, like biomass, and you try to look at them as part of the study process, how much variation you're seeing in this group of units. And, of course, no matter what clustering of units that you have, the more you aggregate units the more well behaved they become.

For example, if you look at a specific wind generator it could be moving around a whole lot, you know, going from almost nothing to full-out capacity within a few hours. If you take and aggregate 300 of them across the state and looking at them in total, they will act much smoother and much more predictably.

So the question is how much aggregation do you use; and what units do you aggregate together in order to get realistic models as to what is happening on the system and what the effect is that's caused by these particular kinds of units.

Geothermal units tend to also be very

dispatchable and well liked by our dispatchers because they can count on what the geothermal plants are going to do from hour to hour and day to day. And so again you can see some very nice, again as you aggregate these particular areas they look very nice.

Solar has, of course, a pattern that you would expect. It goes dark at night and you don't see any solar. But in the morning when it comes up, you see some fairly nice predictable patterns that come up. And, of course, some of these solar units are also supplementally fired by gas, so that you have, again, a more dispatchable predictable type of generation output on these.

The wind generation moves around a lot more. This is not a surprise to anybody. And the question is how well can we handle that. And if you can predict it or forecast it, would that improve your overall supplemental energy dispatches and your regulation requirements. And what is the impact of that.

So we looked at specific areas including Altamont, San Gorgonio and Tehachapi. You have to remember this is 2002 data, so we did not have big wind farms like Solano that are in there at this point, and other areas that are still developing with some of the newer wind turbines. These areas tend to have a lot of the older generation of wind turbines, smaller sizes, smaller blades and also lower to the ground; and they tend to have a lot of variability compared to what probably some of the newer units are. But this was the data that we had for 2002 that we basically were studying.

Again, this is the location of information that if you go to our website you can find a lot of this information. Almost one of the faults of our website is that we publish so much information it sometimes is difficult to find everything on it. But, again, if someone has a compelling interest and has trouble I'd be glad to help them. So you can either contact me or Yuri and we could help point you in the right direction or team you up with someone who can find that information.

Again, we do try to publish a lot of information about both prices and units that are offline, and information that's available that is publicly -- can be publicly available without going into the confidentiality type areas.

We do, one of the big issues for us is, of course, the forecasting of the load for the hour-ahead market. We have an hour-ahead market as well as a day-ahead market. We try to, you know, and for the hour-ahead market we basically are looking at about 2.5 hours in advance of the start of real time. So if you're going to do good forecasting for wind you need about 150 minutes out ahead of the start of real time in order to be able to have enough time to put that into the hourly market area. And then say, this is what I predict that the wind will do.

The ideal thing, of course, is if you can forecast it, then you can line up that renewable energy against load and therefore I don't dispatch some other unit, fossil unit, and we can therefore get better advantage of renewable type resources.

The way that our goal is is to try to make the forecast more than accurate. What we're trying to do is to make the forecast unbiased. What that means is that if you take all the forecasts for 4:00 in the afternoon for all the days in the month, and what you would like to do at 4:00, all the 4:00 forecasts, is sometimes be a little over, sometimes a little under, so that if you look at the average over the whole month and average all the 4:00's, it would turn out to be near zero in terms of what your error was.

If you always had, you're doing it on a persistence type model and what you saw was that wind was always slowly diminishing in the afternoon, so therefore you always had an inertia overshoot all the time that would not be good, because you would always be over on the 4:00's. So you have to do more than just go for accuracy; you also have to do it for unbias and do some correction factors so the 4:00 in the morning and the 6:00 in the morning and the 8:00 in the morning and the 4:00 in the afternoon, each within those periods where the pricing is different, all of those things come out as to an unbiased forecast for each of the hourly periods.

The schedules for hour-ahead are submitted basically two hours in advance of the start of real time. And there are times where the daily scheduled load can be off by as much as 5000 megawatts. On a hot summer day, temperatures up in the high 90s, low 100s, what happens is in California the average, a one-degree error in the average temperature at that point results in approximately 550 megawatts of load.

So if you err by three or four degrees on the temperature forecast for 4:00 in afternoon by just a few degrees, you have the equivalent of 2000 megawatts or more that you could be short.

So, of course, the weather forecasts tend to come in like 6:00 in the morning. And, you know, so if they haven't done a good correction of where the real day is going, sometimes, as the operator, you can have some very interesting surprises of being off by some things by a very significant amount.

This is just a picture of doing the hour-ahead load schedules and what the missing pieces are.

And for most of the regulation it's purchased day-ahead. We also do some correction of that in the hour-ahead. And this is based upon, again, what we're expecting coming at us. We procure for different hours of the day, different amounts of regulation. And we do it at this point in two pieces. A piece which is called regulation up, and another piece which is called regulation down.

If you go to other markets like PJM they tend to buy it as one big block. And it tends to be symmetrical. In California what we purchase is not necessarily symmetrical because we tend to buy more regulation down, particularly like at 11:00 at night where the load is going to fall off very rapidly, and you also have large pumping loads that are coming on. So you have different balances of how much regulation up and regulation down you need at different particular hours.

Again, Oasis is the place where the pricing of these things are also published. And if you -- also on our website is a monthly report which is put out by our market analysis group. So if you want to look at pricing trends over a whole month I would recommend looking at the part of the website that's done by the market analysis reports.

If you look at also our website for the board reports, where when there's almost always a part in the board reports that is done by the market analysis group that gives you all the prices and trends and all the major curves for the whole month, for the past month, as to what's happening with the markets and anything unusual. And there's usually about 30-some graphs and curves that they put in there. So there's a lot of information available.

For the supplemental energy purchase, this is the part where the dispatcher is doing the moving the -- yeah, doing the dispatches up and down. And we call those INCs and DECs. So it's either increasing the generation or decreasing the generation to do the load following. And, of course, during this period if you had, for example, a wind generation farm that had an average forecast for the whole hour of say 100 megawatts, but he was starting at the hour at 150 and he's going to end the hour at 50, then you would have a supplemental energy dispatch of 100 megawatts that you'd do during that whole period of time. Or else you'd have to follow with regulation all the way down.

So even though the average might be 100, you could have a significant movement during that whole period.

By doing supplemental energy dispatches every ten minutes you kind of follow it down in lumps or blocks and do not require everything to be done by the regulation units, themselves. So it takes a combination of the two to keep the system in balance.

This is a picture of the generation outage data that's published on our website. And, again, this is generally available information. This goes back to the energy crisis in 2000 where the state -- this was usually in the past held as confidential information. And then the state said we really need to know. So this is now public information.

And so, up next, --

MR. SIMONS: If the Committee doesn't have a problem one of the things that we had been talking about is leaving a ten-minute gap at the end of each of the sessions for questions, as well as having a comment-and-question session at the back end at 4:00. So, that would hopefully speed things up somewhat, but also leave some time for questions. What would the Committee like to do?

PRESIDING MEMBER GEESMAN: I think that would be fine. I am concerned, though, that if we have more than ten minutes of questions we have an orderly way to dispose of those.

MR. SIMONS: Okay.

PRESIDING MEMBER GEESMAN: But why don't we go on your suggested format.

MR. SIMONS: Okay. So, if there are any questions about the data portion of this analysis, then go ahead and come on up, state your name for the record, and supply us with your question.

MR. HAWKINS: No questions.

MR. SIMONS: Okay. Mike Milligan from NREL is going to talk about capacity credit. He'll be -- again, we'll have a ten-minute question period after that. That will be followed by Kevin Jackson from the California Wind Energy Collaborative talking about the load following piece. And then followed by Brendan Kirby from Oakridge talking about regulation.

DR. MILLIGAN: Thank you, George. What we looked at here was using pretty much a standard method for calculating system reliability. And then look at that from the point of view of the -- from the reliable capacity that a generator would provide to the system. This is called the effective load carrying capability, ELCC for those of us that know and love the term.

And what we initially did back in the fall was we did the calculation for the hourly renewable technology such as wind by taking a look at a probability distribution for each of the 52 weeks, actually 24 distributions for each week. And during some of the discussion that we had the past September the idea was to look at this on more of a, sort of a planning type of basis, which is really what we're talking about here, in trying to value capacity in a procurement process.

So we did revise the calculations so that we sort of collapsed the distribution so that we had 24 different probability distributions for each of the months of the year. And the idea was then to take the distribution of power output and put that into the reliability model and see what sort of answer we came up with.

The nice thing about the non-intermittent renewables is it's a lot easier to do the modeling. And so we did that with, for example, the geothermal plants. Actually we had two cases -- I'll talk about that in a minute -- where you simply specify the capacity and the forced outage rate. And that allows us to measure what it is we're trying to go for.

So the idea was we wanted to take a look at the reliability model and calibrate it to sort of a standard level of what we call loss of load expectation. And this is typically measured in terms of the number of hours a year that you would have an outage, well not really where you have an outage, but it's a statistical likelihood. And so what we do is adjust that to one day in ten years which works out to be 2.4 hours per year.

Then the idea was to compare each of the renewable generators with a standard benchmark case, and we used a medium sized gas unit. And the idea then is we ran the model with all the existing generation in the California system. And then one at a time we'd back out one of the renewable technologies; find the decrease in reliability that we get; and then add a gas unit to that until we get back to the original level of reliability.

We utilized forced outage data from Resource Data International's basecase database. We got maintenance schedules for the initial runs we did back in September from the ISO website. We got a whole bunch of data from the ISO PI system on hourly renewable generation.

The results you see here are ones that we presented last September. It turned out that there were some fairly high peak loads in October along with a fairly high level of maintenance scheduled. It happens sometimes that you don't always take units out for maintenance when you might want to. And so the left-hand chart shows the relationship between loss of load expectation at the top load hours of the year.

I'll show you what happens when you remove the maintenance from this in just a moment. But essentially the idea is you see these different types of clusters of points, and I apologize it's a little bit hard to see those. But effectively what's happening is the maintenance schedule has the effect of shifting risk into some relative non-peak hours.

On the right-hand side what that graph shows is the average peak from each month as a ratio of the annual peak. The blue bars show the level of maintenance being performed. And if you take a look at October, fairly high peak along with quite a bit of maintenance being done in that particular year.

So we then took out all the maintenance scheduling and re-ran things. And what you get is a curve, this one I'll blow it up in a second so you can see it a little bit better. What this shows is that during the peak hours, and this is no big surprise, the system is at more risk than it would be in the off-peak hours. And so this particular curve shows some risk, up to about 100 hours or so of the year.

This next graph kind of enlarges it by taking a look at a logarithmic scale on the Y axis. And what happens here is that this shows that approximately a little bit less than 600 hours of the year you have some sort of risk to the system, and pretty much the rest of the year the risk is either zero, or close enough to zero that we can't really measure it.

So this gives us an idea of, you know, if we want renewable generation when is it going to be most valuable to the system from a reliability standpoint. And a graph like this allows us to say when that is. It's going to be probably no more than the top 575 hours, give or take, into the system.

Every generator has its own characteristics, and no generator has a perfect reliability record. So therefore, the effective load carrying capability of any generator is going to be somewhat less in its capacity.

Our generic -- let me back up. Our benchmark plant was a gas plant. And the combined maintenance and forced outage rate added up to be somewhere around 10 percent. And so what we did here as just sort of an illustration of the process, we took a hypothetical 100 megawatt sort of a generic plant and we said let's see what happens if you progressively increase the forced outage rate of that plant. What happens to the effective load carrying capability.

So that's all this chart shows. This is not a real generator. It's just trying to convey what it is that the calculations are doing for us.

So in this case if you have a forced outage rate on a generic plant of 10 percent you can see that you're getting pretty close to 100 percent of the benchmark which also has about a 10 percent combined outage rate. And as you increase the forced outage rate of this generic plant you understandably are going to reduce the effective load carrying capability.

So I think it's of interest if you take a look, for example, at the 70 percent forced outage rate on this graph that translates into roughly, and I say roughly, 30 percent capacity value for this particular plant. And that's what we saw more or less with the wind plants; a little bit lower than that. Some of the other plants pretty much fell in line with what you'd expect based on this hypothetical example.

For the ELCC results we ran this analysis for each of the generating units that were aggregated in the way that Dave was discussing a few minutes ago. I'll spend a few more minutes on this curve because it sort of shows what the process is.

So we take the, in this case, biomass plant out of the system and what happens is the risk goes up to nearly .00045. And then what we do is we add the gas capacity in incremental levels and we keep increasing that until we get back to our baseline reliability level which is our one-day-in-ten-year. And so the point at which these two lines cross gives us the megawatt estimate of the effective load carrying capability of the biomass plant. We then calculated that as a percentage of the capacity and that works out to be just about 98 percent.

We did the same thing on geothermal. Now this particular calculation was based upon the actual time series data that we got from the PI system. We went through the calculation; came up with a capacity value of around 74 percent.

Now we don't really know from the data set how much of the output of the steam plant, of the geothermal plant was the result of steam constraints and how much of it was response to dispatch instructions. And we haven't been able to isolate that. It's something we are working on. So this would represent probably a low estimate of what you would get out of a geothermal plant.

And to give a comparison we said well, what if you had a geothermal plant without any steam constraints whatsoever, how does that compare to the benchmark case. It compares very favorably to the benchmark case. You got slightly more capacity out of the geothermal unit than you would from the standard gas plant.

We took a look at the solar. This information came out of the PI system. And as a result of the September workshop we had a number of comments to the effect that this number should be higher than it was. We came up with a, almost 57 percent effective load carrying capability for the solar plant. And until we can resolve the problem we don't recommend this number is used in the procurement process.

We did a little bit further analysis of this and this scatter of points shows the output of the data that we received from the PI system. And taking a look at the top 200 hours or so you see quite a lot of variation. Now, if this is real then perhaps the effective load carrying capability is around 57 percent. But if there's something we're missing in the data set then we're not quite sure. We need to look at that a little bit more closely. But this scatter of points does explain why it is that we came up with a number like this one at 57 percent as opposed to what some people were saying that it should be more like 90 percent or something like that. We'll have to keep looking at that.

For the wind sites, these all came in in the mid 20s range. The Altamont came in at around 26 percent. San Gorgonio around 24 percent. And Tehachapi at around 22 percent. These sites all have their own characteristics and we wouldn't necessarily expect them to come out the same. We did see a little bit of variation among them.

Summarizing all the results here. We've got an asterisk by the solar; we're not recommending this be utilized at this point. Geo one and two indicate the geothermal either with the combined steam constraint dispatch instructions or without in the geo two. And this is something we believe ought to be looked at when a geothermal plant bids in, to take a look at what sorts of steam constraints might there be over the lifetime of the plant. And that will have an impact on its capacity contribution.

Our current efforts are to come up with a simplified method for the capacity calculation. The chart that you see on the left is from data in the midwest. And what it shows is how simplified method can do a reasonably good job of approximating the ELCC. The red line indicates the approximation method of the top anywhere from 1 percent to 30 percent of the load hours. The red line got to be pretty close at around 30 percent. This is actually one of the worst examples we've seen as far as those two lines not coming together as much as we'd like them to. But it does at least a reasonable job of getting us close.

The right-hand side of the graph shows us, I believe this is Tehachapi, I can't quite read it, myself. And what happens here is that we're getting a moderate amount of wind during the very peak, the LOLP hours. And then you see a little bit of bouncing around out between maybe 30 and 70 hours. And then the wind kicks in and we got a much higher capacity factor than we have capacity credits.

So we think the simplified methods, as they've been applied in other regions, don't quite work very well here in California because the capacity factor is over stating the ELCC. And so that's something we're looking at to see what we can do to make this simple.

We're looking at the discrepancy between perceived and the calculated values in the solar. That's something we'll answer in a little bit more detail in phase two and three.

As far as bidding, you get a renewable plant that's bidding in; we think that there might be some value in using some sort of a rolling average.

One of the nice things that this does, if you've got three years worth of data is that you're not looking at a specific year which might be either more windy or less windy, or more solar or less solar than what you might expect over the long term. The nice thing about the three-year-rolling average as opposed to going to longer terms is we've seen, for example, in many parts of the west that are going through a drought period, these tend to be multi-year impacts.

And so if there's a correlation, for example, between drought and wind, or solar, for example, we're able to pick some of that up in the moving average. And so as you're moving through a period where maybe you've got a couple of low wind years that gets rolled into the capacity evaluation. If you're in a period of time when the wind is varying and a little bit higher, that also gets rolled into the capacity valuation.

We need to take a closer look at some of the simplified methods. Until we are able to resolve that we suggest using the ELCC as the approximation for capacity credit.

For an established generator the idea would be to use a three-year rolling average. And this really does amount to a performance test. It's sort of an after-the-fact performance test. If you've got a year where the generator is not performing as you expect that gets rolled into next year's calculation and you would get a decline in capacity credit. And vice versa if you're getting a high renewable year.

As far as the procurement process is concerned, if a monetary value can be applied to the capacity value we come up with that would make the ranking, we believe, really easy. The CPUC is looking at a little bit of this. And one of the things that we've talked about is integrating that effort with what we're doing here. This doesn't necessarily -- may not work if California were to move toward the capacity market, per se, but as far as the bid evaluation we think this would be a nice, fairly simple way to go through the process.

Who should do this work in the future? We're not exactly sure. This probably ought to be some combination of the Energy Commission, Public Utilities Commission and possibly the ISO. There is some modeling effort that the Energy Commission does have that utilizes summer reliability modeling. There's a lot of data that's already there and that might be a logical place to continue some of this work.

We'd like to go ahead and corroborate the results with additional data which we'll be doing in phases two and three. And we suggest using either the ELCC or a simplified method on a three-year rolling average.

And we also think it might be of value to take a look at a separate study that looks at the impact of maintenance scheduling on the overall system reliability in California.

Thank you.

MR. SMITH: I'm Don Smith from the Office of Ratepayer Advocates. I had a couple of comments. One is a comment which ORA made but in an entirely different form, and that was the method you're using to find ELCC.

You're doing it iteratively, but both lines are essentially linear, if you look at any of them, such as biomass here. If you just had two points on the line that's not horizontal you could find the intercept relatively easily. And that was put in a different form using an approximation for stability of the system at the Garver Constant.

But more simplified it seems like one way you could simplify your method would be to -- or either use a -- well, just do two points would probably be close enough, but use a searching method that just doesn't try over and over.

Now, if one of these lines was some bizarre form of curve it would be necessary to iterate.

Second comment is on the solar. That ELCC, I, in looking at the graph of points, your figure 40, I cannot conceive how that would come out with an ELCC as low as 56.6 percent. The points on the left are far more important and it goes down, it's practically linear when you did it on a logarithmic scale In looking at the points on the left, if you're just giving them more weight under rough average, you would be, I think, at least 80 percent, is what the ELCC of solar would be. And I can't conceive how those numbers, unless there's some flaw in the method, would come out with an ELCC that low.

And I have one final comment. On the approximating the simplified methodology for ELCC, on your figure 46, if you just look, or in the experience of work done at ORN by me earlier at PG&E, if you just look at the top 100 load hours for wind you get a pretty close convergence. And use the ELCC. In fact, in many cases if you do just the first 10 or 20 hours you're extremely close. So that might be a way to maintain the ELCC method, but cut down the computations greatly without having to go to this taking just the arithmetic average of the top 100 or whatever, which loses a lot of the difference between the highest load and the 100-load hour.

PRESIDING MEMBER GEESMAN: When you did your calculations were you looking at a specific wind location? Or were you averaging data from the various wind locations?

MR. SMITH: I did it, most recently at ORA it was done for the three main wind sites, --

PRESIDING MEMBER GEESMAN: Separately?

MR. SMITH: -- separately. And then they were all lumped together and done in that way. And in both cases just looking at the first 100 hours is within a few percent of ELCC.

PRESIDING MEMBER GEESMAN: Thank you. Nancy.

MS. RADER: Hi, I'm Nancy Rader with the California Wind Energy Association. I just had a quick question, I think, which is that the values that you got for the geothermal without the steam constraint, would you equate that to a geothermal resource that's not based on steam, which is most of the, you know, all of the resources in southern California? Or do we need to study that resource?

DR. MILLIGAN: Well, I'm not an expert on the geothermal technology, but what it's suggesting is regardless of the fuel -- let me back up.

When we looked at the unconstrained geothermal case that was modeled more or less as a generic plant the same size as the geothermal units that we already had in the model.

So that the difference that we found is actually as a result of any type of a fuel constraint. And so I guess our recommendation is to take a look at geothermal units if there's a possibility of a fuel constraint over the lifetime of that plant, because that would make an impact on the ELCC.

I'm not sure, does that answer your question?

MS. RADER: Well, I'm just wondering if there's anything unique about non-steam-dominated geothermal resources that would merit an evaluation of those resources since I think you only looked at the Geysers resource.

DR. MILLIGAN: Right.

MS. RADER: And then you modified it to get rid of the steam constraint. But I'm not sure that mimics the other types of geothermal resources in the south.

DR. MILLIGAN: Dave Hawkins agrees, so I agree with Dave.

(Laughter.)

MR. HAWKINS: It is one thing to sit in the office and crunch the numbers on this data, and think that you understand the operation of these units. And it's really quite another thing to go out to a site, talk to the plant operator at the site and really understand the constraints that they operate within and the kinds of changes that they make in their dispatches. And also how they interact with whoever is sending them dispatch notices.

So, as we've gone to wind generation sites and as we talked to the Geysers units, we learn a lot more that is behind the data and why you get some of the responses that you do.

So I totally concur that without doing

some of these field trips and field visits you really have to stretch imagination sometimes as to really thinking that you understand exactly what are the constraints on these places.

And so, for example, we are planning a trip to the solar plants to talk with the plant operators and their schedulers to understand better how they work. And certainly agree with you that it's probably well in order to do that with the other geothermal facilities.

PRESIDING MEMBER GEESMAN: Tom.

MR. TANTON: I call your attention -- Tom Tanton with Vulcan Power and Sylvan Power Companies. I call your attention to slide number 34. I just have a question of clarification.

When you illustrate here the ELCC is a function of forced outage rate, when you apply that concept to the wind generators do you include lack of wind as a forced outage? Or is it a nonscheduled outage?

DR. MILLIGAN: It's essentially a forced outage.

MR. TANTON: Okay. A little comment on the geothermal. I agree that the non-steam-constrained systems need to be looked at more generally. As I commented at the hearing last week geothermal resources are generally managed on a resource basis rather than on a planned basis. And I would suggest as you look at those non-steam-constrained kind of concepts that you do it on a resource basis or a field basis rather than on an individual plant basis.

DR. MILLIGAN: Absolutely.

MR. TANTON: And, yes, they do operate fundamentally different than the steam plants.

PRESIDING MEMBER GEESMAN: Sure.

MR. GRIFFITH: Dana Griffith with NCPA. Just a quick clarifying question. You said these numbers are relative to a thermal plant. I couldn't discern what the forced outage rate of that thermal plant was.

DR. MILLIGAN: Are you talking about the benchmark?

MR. GRIFFITH: Yeah, the benchmark plant.

DR. MILLIGAN: You know, I'd have to check. I believe the forced outage rate was somewhere around 4 percent with a maintenance outage rate around 5 or 6 percent, something like that.

MR. GRIFFITH: Okay, so about 4 percent forced outage, 5 percent --

DR. MILLIGAN: Something --

MR. GRIFFITH: -- maintenance?

DR. MILLIGAN: Right.

MR. GRIFFITH: Thank you.

PRESIDING MEMBER GEESMAN: Sure.

MR. SIMS: Robert Sims with SeaWest. I just wanted to clarify on two slides. Your slide number 50, I believe you mentioned the title to that slide should be new procurement? I just wanted to clarify that was a missing title from that?

DR. MILLIGAN: Yeah, I guess so. Thank you. The idea is that what we're trying to come up with is a value of capacity that the renewable generator would provide to the system. And so, yes, that would be part of the procurement process.

MR. SIMS: Okay. And then back two slides on slide 48, under the first bullet. You say used class average for that technology. As it applies to wind would you propose that you would use the class average by region, the Altamont or San Gorgonio?

DR. MILLIGAN: Yes. Yes.

MR. SIMS: Thank you.

PRESIDING MEMBER GEESMAN: Other questions at this stage? Okay, let's go on then.

MR. KIRBY: I'm Brendan Kirby from Oakridge National Lab. I'm going to talk about regulation and load following.

As Dave said, you're looking at -- with regulation and load following what we're looking at is the minute-to-minute balancing of the aggregate generation in load. And here what we can see is the green line is showing the minute-to-minute fluctuations in the power level of the overall system. It's a morning pickup from 7:00 in the morning to 10:00.

And that can be decomposed into the blue line which is a smoother ramp-up, which would be taken care of by the say the ten-minute market. And then the red line which is on an expanded scale so you can see it better, which are these minute-to-minute fluctuations.

The physical distinction is that, as Dave said, these minute-to-minute fluctuations, they're kind of random, moving up and down. Those are taken care of through the AGC units. The more general ramp which you can predict and you know it's coming about are taken care of with the -- through dispatching more economic units.

So you have these two services, regulation and load following, that have different characteristics. They're both addressing this time varying balance of generation and loads. They're both doing sort of the same thing. Very important concept.

The system, you treat the entire control area as one so that in the system you're balancing the aggregation of all of the loads with the aggregation of all the generation. And in regulation you're matching the minute-to-minute, whereas for load following it's a longer term, it's a slower ramp-up.

To get the resources to provide regulation are units that are online. So it's a generator, it's online, it's not fully loaded. It's not at its minimum load so it's able still to move down. It's not at its maximum; it's able to move up. It's got automatic generation control and it can rapidly move. So you've got a pretty good megawatt-per-minute movement.

The cost for supplying regulation, and the heat rate does get degraded some in a typical unit supplying regulation. The primary cost, though, is the opportunity cost. The unit is not at its full output. It can't be selling into the energy market. So there's a lost opportunity. It's also forced to be online, so if it's providing regulation in the middle of the night, it may be forced above its economic point. So there's again a cost there. And these resources are procured through the regulation market.

The load following you're running longer term. It's very similar to regulation, but longer term. The generation is meeting the hour-to-hour and the daily variations, so it's ten minutes to an hour. Interestingly, FERC did not establish load following as a recognized ancillary service, whereas it did establish regulation as one. So it's provided out of the hourly and sub-hourly energy markets.

Again, you know, kind of summarizing that, the patterns for regulation are different. It's random and uncorrelated, these minute-to-minute movements, whereas for load following it's largely correlated and easily predicted. You're going to be ramping up every morning; you're going to be dropping every evening.

You've got to have AGC for regulation; you don't necessarily have to have AGC for load following.

The swings out of regulation are relatively small. The swings are much larger for a load following. On the other hand, the swings are much faster for regulation and slower for load following.

So, to do a regulation analysis. The data you need is the one-minute total-system load data. You've got to know how the system is moving minute-by-minute. And you also have to know how the individual unit that you're looking at is moving minute-by-minute. Individual generator, you can also do this for an individual load.

And you also want to know, on an hourly basis, how much regulation are you purchasing.

And you also want to know what that price is. Because, as Dave said, regulation is purchased in hourly blocks and the price varies from hour to hour.

And here what we did is we're allocating the cost of regulation. So we're not explicitly, or we're not exclusively looking at the minute-to-minute variability. More importantly what we're looking at is the total amount of regulation that the ISO was purchasing, how do we allocate it appropriately to all of the individuals that are causing these fluctuations. So it's an allocation. To do that you want to determine what's the total system requirement.

And what we use is the one-minute movements of the total system to find out how does that correspond to the hourly purchases. We separate regulation from load following, so we separate these movements which turn out to be a capacity type function from the energy, the load following energy component.

It turns out that hourly standard deviations of the one-minute movements are pretty good. You know, those are a very good metric for determining what the regulation requirement is.

So we go and we look at the individual regulations requirements from each individual that we're wanting to italic out. We then allocate that to the total. The important point here is that unlike with energy where your energy requirements from a number of individuals add linearly, they don't with regulation. They typically go up with the square root of the sum of the squares if they're completely uncorrelated. The analysis didn't rely on how it actually looks at any correlation that might be in there.

So, we're doing that allocation. We're looking at the hourly system regulation purchase amounts. And then we're looking at the hourly prices.

So when we go back and calculate out what the cost is, it's not only looking at how much you're using each hour, but then was that a cheap hour, an expensive hour.

And here's looking at the total system regulation requirements. And again it's using total system load. So this is the total the system is going to have to purchase regulation to compensate for.

And this, the graph is showing the regulation standard deviation.

Okay, this is looking at a specific resource; this happens to be solar. And it's looking at both, the top graph is showing you what is the variability of that solar plant; the bottom graph is showing how that ends up allocating out. You'll notice it's significantly smaller. The reason it's always smaller when you go is because regulation is a service where this aggregation is incredibly important. It's the reason that for almost a century we've been having control areas that want to become larger. The larger amount of load and generation that you're encompassing it makes the control problem easier in terms that it reduces the total regulation burden.

Here the actual regulation purchases. As Dave said, California purchases up-regulation and down-regulation. And the regulation, the ratio, as I said, we're using standard deviation, hourly standard deviations of the minute-to-minute fluctuations. And you look at ratio turns out to be for California about 6.5 for regulation up; 6.7

for regulation down. That is buying about 6.5 times as many megawatts of actual purchased regulation compared with the standard deviation.

And here's looking at the regulation prices, how they vary hour-by-hour. And there's a different price for regulation up and down.

And here's looking at the allocation where you're taking that entire analysis, you're now looking at what is the amount of that hourly regulation, amount, and then price or cost, allocating it back to the, in this case to the solar resource. And we're using an easily understood number, and I think a very relevant number as what we come out with. It's the cost is dollars per megawatt hour of generation out of that resource. Turns out that's not a good metric for regulation. You would never want to do your calculations only on it. That's the final result.

What it's saying is not that inherently solar is -- what it's saying is that when you do the analysis and then apply it back to the amount of generation you got, that in this case you're seeing that the cost, spread over the amount of generation, is in dollars per megawatt hour of generation. The point is that the fluctuations do not necessarily correspond to the amount of energy. The cost is coming from the fluctuations, not from the amount of energy.

Will the number end up being a robust number? Well, yes, because the characteristics for solar tend to be that you get that much fluctuation per the amount of energy.

And then here the total results we came up with. And, again, apply in terms of dollars per megawatt hour of generation. Or in the case of load. A negative value means that there's a cost so that not surprisingly when you look at load, you're seeing that the aggregate of the loads end up costing about 42 cents per megawatt hour. So for each megawatt hour of load that you have on the system it's going to cost about 42 cents for regulation.

Then you see the medium gas plant. It's got a positive number. Well, that's because this plant happens to be being dispatched in a way -- it's not providing regulation. But it happens to be being dispatched in a way that it's ending up, on average, benefitting regulation. It tends to be moving in the right direction so it gets 8 cents of credit. The point there is that the analysis methodology will find positive -- it will find someone who is benefitting the system even if it does not know ahead of time that that individual is trying to say follow an AGC signal.

Biomass, it turns out it was not -- it was fairly flat and it was not having an impact either plus or minus on regulation, so it's zero.

Geothermal. Just do to the way the fluctuations are going, in this case, for this analysis it was 10 cents per megawatt hour of cost.

Solar ended up being positive, 4 cents. All these numbers are extremely low, so it's difficult to place a tremendous emphasis on saying, well, gee, solar was actually positive 4 cents.

Then you look to the wind and you see there is a fair amount of diversity. The Altamont, for this study period, had no net impact. Whereas San Gorgonio was seeing 46 cents of burden; Tehachapi 17. You looked at the total and it turned out also to be a 17.

So, fairly low numbers. These fairly low numbers are also consistent with other studies that have been done. Here's looking at a number of studies. You have to dig into the studies a little bit and recall that we are looking at regulation; and then we'll look separately at load following. There are a number of characteristics these various studies looked at.

So, the study for Xcel Energy, for instance, it came out with a $2 per megawatt hour, looking at a 3.5 percent penetration. But there were large forecasting errors built in -- forecasting penalties built into this study. It was a study of an area with no hourly markets, so there was day-ahead forecasting. Ends up imposing a large cost. And the predominant portion of that $2 per megawatt hour is a day-ahead forecasting error penalty.

Pacific Corp was a 20 percent penetration. And there they found $5.50, which is a pretty good number. Though when you go through the study it did not particularly look at regulation, and in fact, the people doing the analysis assumed the regulation burden was zero for that study.

Eric Hirst did a study for BPA with a 5.9 percent penetration. And there he found $1.37 to $2.17. But, again, this study included a large forecast error penalty. And the majority of the costs in that study come out of forecasting error.

Wisconsin, similar studies, similar high numbers. Again the forecast error dominated that study.

And PJM study that -- another study that Eric did. And there he was breaking out specifically the regulation cost, and he was coming up with 5 cents to 30 cents. It was a very low penetration.

That's all I have on regulation.

PRESIDING MEMBER GEESMAN: Questions? Tom.

MR. TANTON: Thank you. I'm still Tom Tanton.

(Laughter.)

MR. TANTON: On your slide designated 65 regarding regulation cost results I have two quick questions. Was the geothermal based on the type 1 or type 2 unconstrained?

MR. KIRBY: Very good question. Henry?

MR. SHIU: That would have been the raw data --

MR. TANTON: That would have been the steam-constrained system, okay.

And on the wind total at the bottom, is that based on existing or is that based on resource potential in the different areas?

MR. KIRBY: Oh, no, that's all -- this is all real --

MR. TANTON: That's just existing, okay.

MR. KIRBY: Yeah, it's real data.

MR. TANTON: All right. I also have a question on the regulation cost, slide number 54. Did you include the increase in emissions from the gas plants that are providing the regulation service?

MR. KIRBY: That is one of the neat things about the way we did this study is these are the costs that tend to go into it, but the costs that we look at are actually what is the regulation market price. So what was paid for regulation.

MR. TANTON: Right.

MR. KIRBY: So we're just saying these are the costs that tend to go into it, but the actual price is based on whatever the regulating unit bid.

MR. TANTON: Okay, so would it be fair to say that no, it does not include any emission increases as a result of running at a degraded heat rate?

MR. KIRBY: I would assume that's true unless that's something that the gas plant builds in when it goes and bids.

MR. TANTON: Okay. Similarly, the increased wear and tear on those gas plants, I guess would be reflected somehow in their price offered?

MR. KIRBY: Now, that I would expect would -- yeah, I would expect that would be in the price offered, yeah.

MR. TANTON: Thank you.

PRESIDING MEMBER GEESMAN: Other questions? Yes, sir.

MR. GRIFFITH: Dana Griffith again. Just a quick question. I'm not sure I understand the difference between your approach and the ISO's approach. Because my understanding of the ISO, they came up with numbers that were significantly higher to the tune of about a factor of 15 to 20 times higher.

MR. KIRBY: Well, here what we're reporting on is the phase one study. And the only work that was done on the phase one was this first method. So I'm not able to respond to that at this time.

MR. GRIFFITH: All right.

PRESIDING MEMBER GEESMAN: Other questions? Okay.

DR. JACKSON: Okay, so we're going to go on to load following. Load following is basically looking at how would the renewables affect the stack. When you go to load following you're pulling bids in. It's in a computer, it's not a real stack. It used to be an actual stack of paper, but there's a whole range of bids that come in.

And so one of the questions we were looking at, really the primary question we were looking at was would renewables in the system shift the stack in some way to increase the cost.

Because if you were to shift the stack you could incur costs across the whole system because of the way that the bidding works. The last accepted bid sets the price.

So we're really looking at the hour-ahead market and how does the stack shift with or without renewables.

When we first started looking at this one of the questions we were asked was is the supplemental energy, energy and balance market an integration cost. And after quite a bit of discussion it was basically understood that those market costs are explicit. They're built in with the amendment 42. And so that they're not hidden costs and therefore are not really integration costs. Because we're trying to find costs that are hidden and borne by the system that are not explicit.

So, we're not looking at this case of imbalanced costs. We're looking at this deformation of the stack by the renewables coming into the system.

So the method we came up with uses hourly system loads, schedules and forecasts. We showed you those before. And those were pulled from the Oasis database. And then we've got the hourly renewable resource generation data which was originally pulled as one-minute data, and then converted into hourly averages.

So we've got bids and schedules that are coming for the hour-ahead market. They're provided 150 minutes ahead of time. And then we have hourly average values that are coming from the ten-minute supplemental energy market.

And then we used what's called a naive persistence model. And it's a very very simple model. And what we said is for forecasting we're going to assume that the output 150 minutes from now is equal to now. So it's not really a true forecast; it's just -- it ends up just shifting the power output by 150 minutes later. So it's the most simple forecasting model you can get.

And then we looked at that and said how would that affect the forecasting error in the system. Now, for solar we used a slightly different model. And that one was shifted by 24 hours, because it's a solar system and it's going to attract the sun a little bit much more than it is the 150 minutes ahead.

But, again, it's not a true forecast. With the forecasting system that ISO is implementing we would expect much better results than what we're seeing here. So this is just the worst case.

So we're getting a forecast hour-ahead load. That's coming from Cal-ISO. That's their best estimate of what demand is going to be 150 minutes ahead of time. And there's quite a bit of variation in that. Red is the maximum. This is 24 hours, but it includes all the year, so the maximum around that. In general it's unbiased. So over the course of the year the forecast doesn't try to forecast low or forecast high; it forecasts on average about what the demand was.

But the schedule is biased. So the forecast is put out by ISO. That goes to the scheduling coordinators. And the scheduling coordinators are actually scheduling power significantly less than what the forecast was. So there's a built-in bias. And in some cases that bias is as much, scheduled load can be as much as 5000, but the bias on average can be about 800 megawatts, 800 or 900 megawatts.

So, the difference between the schedule and the actual demand is a scheduling error. You can see there's some pretty big differences on any given day there's a lot of scheduling error that occurs. Again, this is the schedule, not the forecast. The scheduling coordinators are actually scheduling in more error than was forecast just by the weather. And they're scheduling it down. And they're leaving open some head room to go buy it in the market.

This is the rest of the year. And then this is a plot of the scheduling bias. So the bias is the difference between what was scheduled and what the actual forecast was. So you take Cal-ISO's forecast and the schedule, and the difference between those is the bias.

And, again, we're tending to bias negative so that you can reach to the market to get supplemental energy.

This chart's a pretty good example of you can see on any given day, a good one in the lower left, you'll see we're starting in September. There's a day that is on the first where it's significantly under scheduled. And you can see if there was a lot of concern about getting resources in the market, you'd expect that the next day the schedule would be better. But it isn't. They know that they can reach to the market to get more energy. And then the third day it does the same thing again.

So what we've ended up using this for, the scheduling bias gave us a proxy for estimating the depth of the stack. So we needed to know how much generation is out there that you can go and get on any given day. And we use this scheduling bias as a proxy for telling us that. And that was our proxy for the depth of the stack.

So, then the process became we've got a proxy that tell us here's how deep the stack is. And we had done this naive persistence model where we said here's the forecasting error just by itself. And here's the forecasting error with the renewable of interest. So you would add in the error that was created by this, and we were generating that from this naive persistence model, which is the absolute simplest forecast model. And then looked at those and said, is there significantly more forecasting error with the renewable than there was without it. And compared that back against the stack depth again, which the proxy for the stack depth was the scheduling bias.

And in general what we found is that the scheduling, the changes coming from the renewables were very small relative to the scheduling bias. And so therefore there was in all likelihood that we were just stored in the stack. The stack was so deep that the small changes in forecasting error with the renewables were not going to significantly affect the way the bids were coming in.

So at this level of penetration the stack appears, it looks like renewables are having a negligible effect on the stack.

So the recommendations that we came out with is that it's a negligible penetration at this, or it's a negligible effect at this penetration. That the scheduling bias is determined by the scheduling coordinators, so one of the questions we had was how is that process determined.

It's not completely clear to us exactly

how those schedules are put together. We're pulling data from Oasis as to what the schedules were. But changes in the way the scheduling coordinators do things could have some impacts on this.

At this point we're recommending that there's no load following cost adders. And again it's because we're not seeing any effect on the stack, and it looks like amendment 42 is covering all of the explicit costs, which are not really included.

And then the final one is to look at this under some higher penetration levels.

PRESIDING MEMBER GEESMAN: Questions? Tom.

MR. TANTON: I apologize, I have another question on the regulation costs. I know we're backing up but it will just be real quick.

Did you look at or do you plan on looking at the elasticity of prices of regulation as more or less regulation as required?

DR. JACKSON: I'll let Brendan answer that one.

MR. KIRBY: That's a good question.

MR. TANTON: Thank you.

MR. KIRBY: -- so small -- for there to be a significant problem from that you would have to see a dramatic non-linearity in the regulation, so you'd have to know that you're right up against the edge of what you could possibly regulate. There's no evidence that that's true.

I think we would be aware if there was a strong need in the cost curve of regulation; we're not aware of that.

MR. TANTON: Well, I think it's a function of two things. One is the amount of regulation available; and the other is the amount of regulation required. And if the required becomes, in some amount, more than available --

MR. KIRBY: Yeah.

MR. TANTON: -- bidders are going to bid their price up. And conversely, they're going to bid their price down if there's, you know, if it's a real fat market.

But you haven't looked at that, is that correct?

MR. KIRBY: That's correct, we haven't looked at it, --

MR. TANTON: Okay.

MR. KIRBY: -- but also there, I think if we were near the -- of that kind of a curve we would know that, and there's no reason to think that we're anywhere near that. But no, we haven't --

MR. TANTON: Okay. Thank you.

MR. HAWKINS: Back in the early days of the ISO, the first year or two of operation, we procured probably twice the amount of regulation that we procure today. So we're up like 1600 megawatts of regulation capacity. Today we procure somewhere between 600 to 800.

And we certainly affect overall cost, you know, when you buy that much additional regulation. But our tools were not as good as they are today. And therefore you cover up, you know, the lack of good tools by having a lot more regulation.

And, of course, the costs have changed over the last five to six years. It used to be we paid somewhere around $30 a megawatt for regulation. Today that number is a lot lower. I suspect, you know, if your demand for regulation went back up to 1000 or 1200 or so forth, it probably would change.

But also, I think the portfolio of units that are providing regulation has moved around some; and also, because we're a hydro-rich resource in California, the ideal regulation comes out of hydro, which is very fast. However, if you have very low hydro years you tend to hold back the hydro and to move it on others.

So there's probably a lot of factors that affect the overall price of regulation; and the regulation market; and who you have as players in the market.

MR. TANTON: Thank you.

PRESIDING MEMBER GEESMAN: Other questions? Yes, Don.

MR. SMITH: Don Smith. You used what you called a naive persistence model for wind. Now, actually there is a daily pattern for wind, and it's evident on your figure 18. It's not as clear, of course, as the solar daily pattern which you show on 17, because the sun never shines at night, of course.

But given the pattern, could you have

done a little better with wind prediction instead of just saying it's going to be blowing next hour what it was the last hour, to look at the time of day and add on the expected curve with the peak in late afternoon? And would that have made much a factor, do you think?

DR. JACKSON: You can do a lot better. This is the absolute simplest model. That's what we said, and we're going to use it as a worst case. You couldn't come up with a simpler model to apply. And there are plenty of better ways.

I think the right way to look at this is now that we've got some plants that are actually operating, and I'm not sure if the forecasting system is completely up and running, but it will be shortly. We can start to look at the error that's generated between the hour-ahead forecast and the actual deliveries based on a real forecast. And Cal-ISO will be getting that data relatively soon, if it's not already on line.

So we really looked at this as a worst case scenario. And the costs still came out, or the effect on the stack still came out as being a negligible effect.

PRESIDING MEMBER GEESMAN: Other questions? Okay, shall we move on?

MR. SIMONS: Are you guys going to use the overheads or are you going to load the disk?

UNIDENTIFIED SPEAKER: Put it on the disk.

MR. SIMONS: Okay.

(Pause.)

MR. ALLEN: Good afternoon.

PRESIDING MEMBER GEESMAN: Hi, Gary. You should introduce yourself for purposes of the record.

MR. ALLEN: Gary Allen, Southern California Edison.

Southern California Edison appreciates the opportunity to comment on the phase one report. We have attempted to participate in this study since it was initiated. And generally we did not feel that the results which were being produced are representative of the conditions that we've experienced, having operated with more renewable resources than any other utility in California for nearly 20 years. Both as a vertically integrated utility and more recently in whatever you want to call the market.

On December 10th when the final report was released Edison felt that our comments and concerns had not been adequately considered. At that time we asked Dr. Ed Kahn with the Analysis Group to look at the study. Initially we just wanted to focus on the ELCC calculations.

He's prepared to give us some preliminary results of his analysis today. But based on his review of the ELCC calculations, as well as a very cursory review of the other phases or the other aspects of the report, Edison is even more concerned about the representative nature of the results.

We have, and we have had, and we expressed these concerns in our comments. And Dr. Kahn's work to date has only heightened our level of concern.

PRESIDING MEMBER GEESMAN: Now, the comments in which you expressed your concern, were those the written comments that you provided to the --

MR. ALLEN: Yes, --

PRESIDING MEMBER GEESMAN: -- report

previously --

MR. ALLEN: -- it was.

PRESIDING MEMBER GEESMAN: Okay.

MR. ALLEN: At the very least we are concerned that the current study does not meet the established goals found on page 4 of the report. Specifically we don't believe that the study uses input data and analysis tools available in the public domain. We don't believe that it is fair, transparent and coherent. And finally, we don't believe that it is clearly defined, reputable or analyst independent.

SCE believes that the use of the results from the phase one report is premature. And we are prepared to continue our own independent analysis evaluation. We would be willing to cooperate with the Committee in order to obtain results that are representative and meet these goals. And we'd like to pursue that.

Thank you. I would like to offer Dr. Kahn and his preliminary report up for your consideration.

PRESIDING MEMBER GEESMAN: Thank you. Ed.

DR. KAHN: Thanks. I think Gary's already set the stage here. Edison asked me to review this report and to make an independent assessment. So I want to discuss what I did, what I found, what I think.

The methods that are, and this is a discussion confined to the ELCC -- the general methods that are described here are reasonable, standard and we implemented very slight variation, not material.

It's just that we don't understand how they actually did it. And the primary concern is the one that Gary mentioned, that there's proprietary ISO data. We don't have access to it, so, you know, maybe if we had it we'd agree. But we don't, and we tried to do something else cleverly, we think.

But we don't get the same answer. So, what we did was rely on lots of the public data that's on the website that was described earlier. But there's some other stuff which is crucial for an exercise like this which is not on the website, but which is available to us, thanks to the Federal Energy Regulatory Commission, and its investigation of the western energy markets and the refund case.

And so we took advantage of, in particular, the hourly hydro dispatch that was released by the FERC for not 2002, but for related year.

The bottomline is we cannot replicate the ELCC estimates that were produced in the RPS study. Our calculation, using Edison's data for 2002, aggregating it all, is an ELCC of 13 percent, substantially less than what the RPS study found.

So these are just equations and we'll skip those. They're the same ones that are in the report.

So, the key pieces of data, I think I actually would like to add one to the bullet here, yes, the hourly hydro matters a lot. You have to have outage rates for the thermal generators. They used a proprietary database, we used a proprietary database. That's not really a problem because you can go out and spend money and buy data. You can't buy 2002 hydro data. You can subpoena it, but you can't buy it.

So, what we did was we said, well, we know 2000 hydro very well, and we're going to use that as a proxy for 2002.

Now, first thing you might want to do is go look at the EIA data on hydro production for these years and you'll find lo and behold there was a lot more hydro in 2000 than there was in 2002. And we claim that that's interesting but it probably doesn't matter. And we'll say something about why we think that's true.

The other problem is that in 2000 SMUD was part of the ISO control area. 2002 SMUD is not part of the ISO control area. So we have to do something to deal with that. And we do something.

So, what do we basically find? I mean I think there's a lot of intuition here that some of which has been shared earlier with which we generally agree, that the ELCC depends upon the coincidence of the wind output with the high LOLP hours. I think everybody agrees to that.

We've looked at a couple of years and we see variation in that correlation. For 2002 we actually think that the correlation is low that year. We've taken a look at 2003; we think it's higher in 2003.

Probably the key issue is the one of how many hours count. We heard various estimates earlier. Is it 600, 100? Is it 10, is it 20? My read of the RPS report is that their answer is 50. And fundamentally our answer is 20. And we think that probably explains the difference in the result.

And this picture, I think, can help people understand it. These are, the solid line is the LOLP hourly over-the-top 100 hours. And so you can see that it's, in this graph, around hour 20 we're getting down to zero.

And then the red line is the hourly wind output in aggregate for Edison's 1000 megawatts of wind. And so conveniently enough you can sort of get a capacity factor for each hour. And what you basically see is that there's a lot of low hours in the -- a lot of low wind output in the high LOLP hours.

Suppose you believed that the LOLP curve actually went out to 50 instead of 20, just sort of pushed it out, made it fatter. Well, then what you would do is you would capture more hours in which the wind output was relatively higher. The ELCC, you know, the calculation's sort of iterative and non-transparent, but when you look at a graph like this I think it becomes a little easier to understand. It's essentially just the weighted average of the capacity factors where the weights are the hourly LOLPs.

So, if we're going further out towards 50 and we're getting more of those high output hours, well, they may not have a huge weight, but they still have some weight. And that would add to the ELCC.

So, when I look at the RPS report and I see that, you know, this, they go out to 50, and that sort of mathematically tells me how they get their answer, but when I actually do these calculations I only go out to 20.

In addition to the hydro confidential data, and we don't need owner by owner, we need aggregates; this is all aggregates. So, it should ease some of the concerns.

But the other issue which we don't understand at all is these wind distributions that were used in the RPS report. And maybe they play a role. But, we don't know what they are. And we'd like to find out.

PRESIDING MEMBER GEESMAN: What do you mean, wind distributions?

DR. KAHN: So at this point --

PRESIDING MEMBER GEESMAN: Ed, can I ask, what do you mean by wind distributions?

DR. KAHN: In the discussion of the calculation they said, well, we don't -- when I showed you my picture before, this is the actual output in the hour. And so when we do our calculation that's what we use, just like we use the actual hydro in the hour and the actual imports in the hour.

The thermal generation we treat as probability distributions with the forced outage rates from a database.

What they do is they say, well, no, we're not going to represent the wind by a point estimate, we're going to represent it by distribution. That there's going to be some probability of what you actually saw, and then some probability of some other thing. And I have no doubt that that could influence the result, but I just don't know what those distributions were, where they came from, and, you know, so this -- the replicability standard, you know, can't even be approached if you don't know how to approximate what was used here.

So, that -- is that clear?

PRESIDING MEMBER GEESMAN: Yeah.

DR. KAHN: It's my understanding that -- we've written all this up; we've done some more sensitivity tests; they all are more or less the same answer. We concocted a case where we managed to get 50 hours of the LOLP spread, but it was one that had LOLE of 15 hours a year. And the only way we could do that is by not installing new generation which we know is there. So, it wasn't much of a representative case.

So, we're going to write all this stuff down and, you know, document it and put it out there for people to review. And hope to push the dialogue along a little bit.

Surely there must be ways to manage the release of some of this data. I'm not very clever at that, but I'm sure other people are.

Similarly, we've taken a look at the regulation and load following, and we've got issues with those.

Generally speaking the analysis seems to be missing what I would call behavioral elements. What we really care about in all these things is what does the ISO do. And, you know, I've spent a lot of time trying to figure that out. And I don't know. But I know that some of the assumptions that were discussed earlier about what they do are demonstrably wrong from my point of view. So it's hard for me to have confidence in that analysis.

And it would seem to me that the correct way to pose the problem is from the behavioral point of view. What does the ISO do? Not how would I allocate things in the abstract using a methodology that is theoretical. But what do they do. So, we'd like to kind of look at that.

So I guess my sum review is good questions, questionable answers. These issues are worth more investigation. I think the study team is doing a good job. But, maybe a little more input, you know, a few economists instead of engineers.

I think we're a ways -- from my point of view I don't make policy for this state, I just pay the bills. And so I'd like to see policy in this area, you know, get made with a little broader dialogue, a little more discussion, and those goals that were in the report, which are, from my point of view, very good goals.

So, we'll have a report on ELCC. And perhaps we'll have some additional analysis on these regulation and load following issues subsequent to next week.

PRESIDING MEMBER GEESMAN: And when would you expect to have the report on ELCCs?

DR. KAHN: My understanding is that you're requiring written comments by next Friday. And we're planning to have that by Friday.

PRESIDING MEMBER GEESMAN: Okay. Questions for Ed? Don.

MR. SMITH: I'm Don Smith. In the procurement proceeding the Office of Ratepayer Advocates requested the output of the two main wind areas in Southern California Edison territory for the last three years, and for the high load hours. And we got them, and I did an ELCC study. And we mention in our comments, just in general terms, that we got numbers in the 20 to 25 percent average for the last three years.

And I just am not sure why, assuming we started with the same numbers, I don't know why our results are so different. I'd like to see your report. But if it's not going to be public until we have to make comments, that'll be a difficulty.

And when I ran those studies I requested from SCE, not knowing whether I really had to or not, but did ask if I could make it public, the specific hours, specific years, and the results per year. And I never received, despite a couple of inquiries, and going to higher levels, the permission from SCE to give out the exact numbers that went into our results.

So I'm -- well, I guess I'd like to ask SCE if I can do that by next Friday. And I'd also, in some form, like to know exactly what formulas they're using for the ELCC for your study. And also compare some of the hours to make sure we're working from the same data set.

DR. KAHN: One of the things we will do is we have an output format that we like which tells you hour-by-hour what's the LOLP for that hour, what's the hydro schedule, what's the imports, what's the wind output. And that should be enough to do it, I think.

So, it is my understanding that the wind data for the relevant hours that we used in these calculations will be part of that report. As for the rest of it, I don't speak for Edison.

PRESIDING MEMBER GEESMAN: Gary, did you want to respond to Don?

MR. ALLEN: I'll do my best. I'm still Gary Allen for Edison.

We provided Don with some data. Part of the data were hourly load data for SCE. And I believe our concern was the hourly load data for SCE, which was to be maintained as confidential.

I don't know that I have the authority yet, but I certainly am going to take it back and make sure that we can provide the aggregate wind data that we used for this report publicly. That seems like a reasonable thing to do.

And the other half of the equation here

is the ISO data, rather than SCE load data. And I think we all have access to that.

PRESIDING MEMBER GEESMAN: Well, as you know, the ISO is governed by tariff that does, in fact, restrict what data can be made public.

MR. ALLEN: Correct.

PRESIDING MEMBER GEESMAN: I don't envision us being able to change that. In fact, I'm quite grateful that they have made what they have available. It is a real breakthrough in terms of work that the Energy Commission has done with the ISO. And I'm hopeful we can build upon it in the future. But I think everyone in the room is probably familiar with the restrictions in the ISO tariff and the extreme unlikelihood that that will change at any point in the foreseeable future.

MR. ALLEN: Right.

PRESIDING MEMBER GEESMAN: But I do commend you for your commitment to transparency and am hopeful that that spirit can spread, not only within your company, but within the industry.

MR. ALLEN: I will leave that as a -- just where it is.

(Laughter.)

MR. ALLEN: I don't plan on making any commitment one way or the other on that.

PRESIDING MEMBER GEESMAN: Other questions? Sara.

MS. MYERS: Since I don't understand formulas of any kind, you don't have to worry. Those aren't the kind of questions I'll be asking.

My name is Sara Myers; I represent the Center for Energy Efficiency and Renewable Technologies. First I want to thank Commissioner Geesman for having this hearing today, and moving along the agenda on RPS implementation. CEERT is very grateful for that.

Because as part of the PUC's decision the phase one integration cost study is an important part of bid ranking. And in order to move forward to a solicitation we need to complete this step.

So I guess my concern about Edison's recommendations here today is what they mean to completing that step. So, Dr. Kahn, what are you recommending today that this Commission do? I don't think I understood.

DR. KAHN: My brief here is not to make policy recommendations. I'm here as a technician, as a mechanic. The numbers is what I'm here to talk about. There's a zillion ways that the results of this could be translated into policy recommendations, and I claim no particular dispensation to be wiser than other people about that.

MS. MYERS: Well, let me be more specific. Are you asking this phase one report to be re-run assuming a 2000 year data set?

DR. KAHN: Well, there's a variety of ways that the differences between what I'm able to find and what they find could be resolved. And I'd be happy to discuss the different ways that that could be done.

But deciding on one or the other is ultimately going to be in the policy domain. And, you know, I'd be happy to give you a list of the different ways we could do it.

MS. MYERS: Will we see that in your comments that are filed next Friday? I mean we're not here to guess. We're here to know. And we have to file written comments on Friday, too. And right now I don't really know what Edison's recommending. Is it 20 hours? Is it the year 2000? Or is it 13 percent? Is that your ultimate recommendation here on the ELCC?

DR. KAHN: Well, the number that I'm comfortable with for ELCC for this wind data is 13 percent. And we have some sensitivity studies that will be part of the report. And, you know, so some of them are 14 percent; some of them are 11; one may be 15.

You know, we look at the 2003 data. The numbers are higher because the correlation's better. So, you know, I appreciate that in the policy process one wants closure and certainty. And the policymakers have to weigh these imponderables and that's their job.

MS. MYERS: Okay, well, I think it will be difficult for all of us to know what those are without having seen them by Friday. But we'll submit written comments in any event. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Sara. Yeah.

MR. SKOWRONSKI: Mark Skowronski, Solargenics. Will your analysis also include a look, relook at the solar ELCC also?

DR. KAHN: I don't --

MR. SKOWRONSKI: You had some reservations in the comments you filed on phase one.

DR. KAHN: I don't think that anything we might do on solar will be in Friday's document.

MR. SKOWRONSKI: Does that imply there will be something later on?

DR. KAHN: I've been asked to do a number of things, and I can only do some of them within a short timeframe.

MR. ALLEN: I'm still Gary Allen. Ultimately the intent is to use the model to look at all the technologies. We just haven't had the time.

Much of Dr. Kahn's time thus far has been in developing the model and looking at the wind particularly.

PRESIDING MEMBER GEESMAN: Steven.

MR. KELLY: Steven Kelly with the Independent Energy Producers. As pointed out by Dr. Kahn, I think the policymakers will be looking at the imponderables in a variety of studies. And

I've heard a study that ORA has conducted, but it's not clear to me whether they can present it to this Commission on the Friday deadline. And we'd just like to know whether they're -- if they will be doing that? If they've been released by Edison on the confidentiality rule to be able to provide that for input into this decisionmaking process?

I didn't hear quite closure on that issue.

PRESIDING MEMBER GEESMAN: No, I didn't hear closure, either. But, you know, trying to keep things at an imponderable level --

(Laughter.)

PRESIDING MEMBER GEESMAN: -- let me say that the pursuit of knowledge is never ending. And we're going to stick on the schedule we're on.

MR. KELLY: Okay.

PRESIDING MEMBER GEESMAN: The best is quite often the enemy of the good. And I recognize these tools are going to be improved as we go onward. But the RPS program is going to be around for quite awhile, and there are going to be quite a number of solicitations.

We're on a calendar to facilitate the first solicitation. And we'll use the best tools we can to get there.

MR. KELLY: Okay, thank you.

PRESIDING MEMBER GEESMAN: Tom.

MR. TANTON: Thank you. I'd like to expand on your last comment there, Commissioner. I think you're exactly correct that we have both the timing issue as well as what has been presented to the Commission, the PUC and all the parties involved, as a great opportunity.

One of the questions posed for today's workshop was relative to the uncertainty of the results. And I would suggest that given the magnitude or the likely magnitude of the costs for integration of the renewables, that it be used in the bid evaluation process on a probablistic basis and on portfolio basis, rather than a deterministic basis.

That way one can assume that either Edison's results of 13 percent ELCC are correct; or perhaps the study group's. And going forward, that the working group concept be expanded.

One of my personal concerns is the

potential for public perception, or misperception in this case, of a study looking at the cost of integrating wind by the wind energy collaboratives whose mission is to increase the penetration of wind. When the public hears that they need to understand that it's a very broad and open public process driven by the Commission, as well as the active participation of people with perhaps different views.

And I think that's a great opportunity. Does not preclude the necessity and the smartness of moving forward now, because the integration costs are relatively small compared to the difference in resource cases.

In addition, I think it would make sense to do the bid evaluation for the integration cost component on a case-by-case basis, given the uncertainty associated with the aggregation approach.

Somewhere we need to also look at the lack of a strong market signal to those that might invest in transmission because the transmission system has generally got the lowest utilization factor of anything that people are asked to invest in. And if we continue down a path where that market signal is not provided, we're going to be talking here until we're blue in the face. And the investments in transmission that are necessary for the state to move forward with a robust portfolio of renewable generation will simply not occur.

PRESIDING MEMBER GEESMAN: Appreciate your comments. Sir.

MR. SIMS: Robert Sims with SeaWest. Could I ask you to clarify on the slide that's currently up, The Analysis Group. Is that the study group that presented earlier today --

DR. KAHN: The Analysis Group is a consulting firm.

MR. SIMS: Can you please expand on the membership or who this is exactly, or who's doing this work for us?

DR. KAHN: Analysis Group is an economic consulting firm. We have lots of offices which are listed there --

MR. SIMS: Okay.

DR. KAHN: -- where colleagues of mine work. We're economists. We work, we do a variety of economic consulting. Most of it is litigation oriented. My group in the electricity business has been active in studying electricity markets.

We consulted -- I'm glad you asked me for an advertisement --

(Laughter.)

DR. KAHN: We consulted for the Federal Energy Regulatory Commission Staff in their investigation of the western energy markets. We've done work on the California energy crisis for Pacific Gas and Electric, for Southern California Edison, a number of state agencies and federal agencies who have to be nameless. And we're currently doing work on litigation matters for the California ISO.

So, -- and I might add that approximately 28 years ago when I made my first appearance before this Commission at a hearing on loss of load probability and ELCC methods, thank you.

PRESIDING MEMBER GEESMAN: And you did a very good job then, I should tell you.

(Laughter.)

PRESIDING MEMBER GEESMAN: Other

questions for Ed? Sir.

MR. MILLER: I'm Mauri Miller with California Wind Energy Association. I have one question. With regard to data, it was implied that like the ISO data will be available. And I took the implication of that is it won't be presented, but it's available. I suggest that whatever public data is available be presented also, such that it can be compared.

Obviously if someone uses data you present and then they go gather data elsewhere and don't come up with the same answers, you always have a question, am I using the same data or do I get different answers.

So I suggest that even publicly available data be made available in your report such that it can be certain you're utilizing the same data.

And secondly, you've commented on year 2000 and 2002 and I'm wondering if you looked at other years for the ELCC of wind; and whether you came up with any results that were lower than the 13 percent in any year.

DR. KAHN: We will present some results

on the year 2003. And those numbers are a lot closer to the estimates in the RPS study than what we found for 2002.

With regard to the public data, and that issue, the really crucial thing for this type of study is the hourly hydro. And we'll tell you where to go on the FERC website to get it. And that, in itself, is an achievement.

And like I said, if things proceed according to my expectation you will see these numbers in aggregate in a mind-numbingly boring series of tables that will present the top LOLP hours for various cases that we ran.

And I said we looked at 2003 as well as 2002. Yes.

PRESIDING MEMBER GEESMAN: Other questions for Ed?

Any general comments that anyone wants to make? Yeah.

MR. SKOWRONSKI: Mark Skowronski, Solargenics. Well, let me preface my remarks by saying I don't have the confidence of the skill set to go head to head with this gentleman on the specifics, the details, the nuances of what they've done. I graduated 35 years ago and that skill set long since has gone.

However, within those 35 years I have 27 years at the Edison Company and the other 8 years in the power industry, and I have a certain perspective, a macro perspective that perhaps my younger colleagues, Dave excluded, may not yet have achieved.

(Laughter.)

MR. SKOWRONSKI: I'd like to point out that -- well, there's a presentation here under a capacity credit presentation, and he had a slide that said perceived and calculated.

I'd like to add another category, perceived, calculated and recorded, because I'm talking about solar thermal with gas assist, and there is a record of that technology in SEGS. And for the past 17 years SEGS-3, -4, -5, -6, -7 and -8 have never failed to meet the contract or energy requirement delivered to the Edison Company.

I've got about 15 pages of rebuttal to the report; half of that are statistics that show that the minimum capacity factor during the peak hours, and coincidentally the peak hour for the

Edison Company is about 500, so just by coincidence it's pretty close to the loss of load curve that they're putting out for the top 500 hours. The minimum capacity factor achieved was 101 percent; and the maximum was 109 percent over these last five years.

And, again, let me highlight the fact that during the last 17 years they've never failed to meet 100 percent of capacity factor.

I'd like to further pursue Edison's comments on phase one. And I'm just reading from what they have submitted. "

With respect to ELCC, Edison noted that ELCC for solar was 39 percent -- this has later been changed to 59 percent -- of nameplate. And those for geothermal and biomass were much larger. Frankly this result surprises us unless the solar data you used were based on a pure solar project EGPV and not a gas-assisted solar project."

"If they were supposed to be reflective of the latter, as I think it would need to be, it failed the fundamental smell test. SCE's solar thermal units have, over the last ten years, consistently realized close to 100 percent of the maximum capacity bonus payments." It doesn't say it specifically, but I can present the documents that we've always met, always met the capacity in energy requirements.

And there just seems to be a disconnect between what these learned gentlemen have put together, a very articulate and detailed analysis, and reality of what an overall, aggregated solar thermal power plant with gas assist has achieved over these last 17 years.

PRESIDING MEMBER GEESMAN: Now, the comments you were reading from are the Edison comments that were included as an appendix to the phase one report?

MR. SKOWRONSKI: That's correct.

PRESIDING MEMBER GEESMAN: Okay.

MR. SKOWRONSKI: And I have nothing else. Thank you for your time.

PRESIDING MEMBER GEESMAN: Thanks, Mark.

MR. SIMONS: George Simons with the Commission. Dr. Kahn, do you plan to look at the year 2000 at all for ELCC? Which was the other, when I looked over the wind years from 1996 through 2002, the comparable year for 2002 was really 2000.

DR. KAHN: This is something that I can do if I'm asked to do it.

PRESIDING MEMBER GEESMAN: By your client? If I asked you to do it, you can't commit your client to paying you to do it, can you?

(Laughter.)

DR. KAHN: I'm a person of very limited powers.

So, you know, 2002 was -- excuse me, the year 2000 was a rather vexed year in a number of ways. But I guess most of, as I think about it, most of the grief of the year 2000 would not necessarily come up in these calculations. There were claims of extraordinary forced outage rates by the generators during that year. Forced outage rates that lie on the far tail of the distribution of such experiences, but we would use these commercial database numbers for that.

You would have very low imports, as everyone can recall. And so, yeah, we could do it.

MR. SIMONS: The second question, again I won't anticipate you answering it, but Gary would answer it. I very much agree about collaboration. Obviously even if we got the data right now the team couldn't respond by Friday.

But we did mention in phase two that we wanted to look at disaggregated databases. And we would be very interested in getting the SCE disaggregated wind databases so that we could put those into the phase two results and see whether or not our results are comparable or not.

Would SCE be willing to relinquish that data set to the team? They have kept the ISO data proprietary, and they would keep the SCE data proprietary.

MR. ALLEN: My sense on this issue is we would probably be willing to provide that information. I spent a fair number of hours over the past year trying to work with Mr. Hawkins to try to pedigree the data that he was using with our data. And was unsuccessful in that to a large degree.

I don't know what the reasons for that was, but I was unable to obtain anything that we could compare apples and apples to.

And that's why I used my data for Dr.

Kahn's work. It's data I had and it's data I could provide.

PRESIDING MEMBER GEESMAN: I think that would be very helpful. Do you think you could get Ed to look at the 2002 year, as well?

MR. ALLEN: I think we were referring to the 2000 year.

PRESIDING MEMBER GEESMAN: I'm sorry.

MR. ALLEN: And I think we provided that -- we've got the wind data for 2000. I don't know what the cost impact of doing another scenario is yet. So I'll have to talk to Ed and see what that amounts to.

PRESIDING MEMBER GEESMAN: Sure.

MR. ALLEN: But, I think generally speaking we could probably agree to do that.

PRESIDING MEMBER GEESMAN: I think that would be helpful.

Yes, sir.

MR. RUDNICK: Thank you, Mr. Chairman, and Member of the Commission. My name is Phil Rudnick. I'm here on behalf of landowners that own a wind resource that's estimated to be somewhere in excess of 500 megawatts in the

Jawbone Canyon area, close to the Los Angeles area.

And I have no technical questions. I just have a request. And the request is that this vast renewable resource is sitting idle waiting for things such as this Commission to move forward to implement the mandate of the RPS.

I don't understand all this dancing around, this transparency and that transparency, while the people of the State of California suffer and look forward to an energy crisis sometime in the future.

My request is please move this process as fast as you can so that we can get the benefits of meeting and helping to meet the RPS which this state has mandated that somehow we do.

And I'll answer any questions that anyone may have.

PRESIDING MEMBER GEESMAN: Well, I think your comments are well founded, and certainly, I, myself, share them. Tell me a little more about where Jawbone Canyon is?

MR. RUDNICK: Aha, you want a tour guide. You're welcome down and I'll show it to you.

(Laughter.)

MR. RUDNICK: You know where Tehachapi is?

PRESIDING MEMBER GEESMAN: Yes.

MR. RUDNICK: Well, about 20 miles as the crow flies north sitting adjacent to what you may know as Sky River?

PRESIDING MEMBER GEESMAN: Um-hum.

MR. RUDNICK: To the north, we are the adjoining ranch to the north.

PRESIDING MEMBER GEESMAN: Okay.

MR. RUDNICK: This ranch consists in total of over 60,000 deeded acres. It has some of the most desirable wind resources that's left in the State of California. We would like to move forward on that.

PRESIDING MEMBER GEESMAN: Where are you with respect to transmission access?

MR. RUDNICK: We are waiting and --

(Laughter.)

MR. RUDNICK: -- waiting.

PRESIDING MEMBER GEESMAN: And have been.

MR. RUDNICK: We understand that there has been a preliminary study that cites a substation basically in the middle of this resource that's supposed to accommodate at least 600 megawatts. We would like to do something so that that transmission can get built, and so that that energy can be made available to the citizens of this state.

How it's done is in your hands and others. If there's something we can do, we would be very happy to participate. We don't have the technical knowledge that all these gentlemen have. I'm sure it's all important. But the thing that we have to be careful, we don't want to get into this same thing that Caesar was complained of, while he's playing the violin Rome is burning. And we're running out of time in this state. We have resources; we need to capture them, and we need to do it as fast as we can.

PRESIDING MEMBER GEESMAN: Well, I would encourage you to send that message to as many of the public officials that you come in contact with as possible. I think the Governor is beating the drum to that cadence. And I know this Commission feels that way.

There's some other elements in state government that I think need to get with the program a little quicker. And in particular I think you should demand quick progress from the state on transmission problems.

MR. RUDNICK: Thank you --

PRESIDING MEMBER GEESMAN: We've had those in our sights for a long time and it's time to deliver.

MR. RUDNICK: I'm not sure what door to open to follow that suggestion, but I will find it and I will pursue it, and I thank you for your suggestion.

PRESIDING MEMBER GEESMAN: Thank you.

MR. RUDNICK: Thank you.

PRESIDING MEMBER GEESMAN: Other comments? Mauri.

MR. MILLER: It occurs to me that in the initial study Brendan and Michael came up with a slightly lower number for the ELCC in Tehachapi. And normalized the data for maintenance schedules.

I'm wondering whether you agree with that, Dr. Kahn, agree with that, whether you included that correction to your data, and whether that results in a change in your results, or whether you considered that at all.

DR. KAHN: We tried to follow the techniques in the RPS study and they eliminated consideration of the maintenance outages, as did we.

I think the point that they made, speaker made earlier that uncoordinated maintenance can shift the risk profile away from high load hours is undoubtedly correct. But that's not something that we looked at.

PRESIDING MEMBER GEESMAN: Other questions or comments? Tom.

MR. TANTON: First of all I'm sure glad that you have this decision to make, that I don't have to worry about it anymore.

(Laughter.)

MR. TANTON: You've got two bundles of things, one of which is the things you know and the other is the things you don't know. And you don't know the magnitude of the uncertainty of the integration costs.

At the same time you know that we need

to move forward, implement the RPS, have the procurements and whatnot. That first procurement is going to tell you some additional information that you don't currently have. And that's how much of a difference in actual bid price there's going to be between different resources in various locations and whatnot. And how does that compare to the integration cost.

You have heard today some information that is relevant to putting some boundaries on that uncertainty. Is it big, is it little? For some resources it's little. For other resources it's big.

The question then becomes how do you implement that in evaluating bids that come into the procurement. And it's a very simple decision to make, although perhaps complex analytically and mathematically.

Just like in your investment portfolio. You can see things with a large beta coefficient that have promising returns. And others with a very small beta coefficient that have less promising, but still attractive, returns.

And if you take that portfolio approach

to evaluating the bids, and it's already built into the bid evaluation process, by resource category, baseload, intermediate, et cetera, we can move forward and then at the same time continue to refine the information that different parties are developing.

PRESIDING MEMBER GEESMAN: Thank you. Robert.

MR. SIMS: Doctor, I just have one other question about your presentation. I think, if I understand and recorded correctly in my notes here, -- Robert Sims -- you noted that you felt the ELCC was 13 percent for wind. And that was based on the year 2000 data set, looking at, I believe, it was the 20 peak hours, is that correct?

DR. KAHN: We're looking at 2002 conditions for everything except hydro. So we've got the 2002 loads, the 2002 imports, the 2002 wind data.

Because we do not have 2002 hourly hydro dispatch we had to do something. And what we did was try a couple of different ways of dispatching the hydro against the loads for 2002 under the assumption that the hydro in the top hours is the same in 2002 as it was in 2000.

MR. SIMS: And how many -- you looked at all hours of the year?

DR. KAHN: Oh, yeah, we ran it for all the hours, sure. But, you know, 8700-and-some don't matter.

MR. SIMS: Okay, and then the gentleman with the original study, I'm not sure who wants to respond -- my understanding is that your analysis was based on the 500 peak load hours, is that correct?

DR. MILLIGAN: That's where the primary impact comes, is from the top -- well, probably more like 50 or 60 hours. But we -- I showed a graph that had the LOLP on a logarithm scale, and it registers for about 500 hours.

Now, when we did the analysis we did not restrict our attention to any, you know, 50 hours or 500. We ran the model for the entire year looking at the entire risk. What Ed Kahn said a few minutes ago is true, and I don't disagree, is that you get a lot of risk clustered around those peak hours. And that's where you get a lot of the loss of load probability.

So the question is how does that distribution tail off. We looked at the full year of runs, and if you go back and look at where the LOLP occurs, we probably more or less agree that it occurs in the top, you know, so many percent of hours.

There are a couple of other differences. When we had our workshop in September one of the focus, a lot of comments came up saying, you know, we don't want the number to be from a particular year. We'd like it to be sort of a representative type of number so that whatever ELCC we come up with is going to be some sort of an approximation of what we might expect as we go forward.

So, our calculation method, we can certainly talk about the details of this offline, takes a look at actual wind data, calculates the statistical distribution across certain hours to try to represent that. So I suspect that's going to be a source of differences in our calculations.

The other thing that we did was we looked at the entire Cal-ISO system, not just one of the utilities. So the timing of the risk is going to be different if you look at the entire ISO system versus any individual utility.

I figured if I talked long enough I'd answer your question. I hope I did.

MR. SIMS: I think you got it, thanks.

(Laughter.)

PRESIDING MEMBER GEESMAN: Other questions? Any other general comments? Mark.

MR. SKOWRONSKI: Given some of the concern and reservation some of us are having, not just solarthermal, but with the report in general, I guess, is this going to impact the schedule? Should we develop a new strategy here, or what's the direction we should be taking?

PRESIDING MEMBER GEESMAN: I think you should assume the schedule stays the schedule. And that this is both a phased report that has two more phases to go through. And a phased RPS program that will have a number of subsequent solicitations.

But we are committed to meeting the calendar for the first solicitation. We'll use the best tools that we have available. I'm not certain that I have quite the level of trouble, having read the report and the comments and the responses to the comments, that perhaps the verbal ambience today reflects.

But I do want to reserve final judgment until I've read the written comments next week. But I would assume that we are staying on the schedule that we've outlined previously.

MR. SKOWRONSKI: Thank you.

PRESIDING MEMBER GEESMAN: Mauri.

MR. MILLER: We had some general comments on the questions which will be addressed in writing by a week from Friday when they're due. But we wanted to make one comment. And I think especially in light of the 20-hour analysis it is important.

We believe at the California Wind Energy Association that the analysis of capacity value should ultimately be followed through to the analysis of a bid project, and eventually to the contractual terms of that project.

We wonder whether an analysis of only 20 hours a year is something that even a thermal generator would agree to basing a large portion of his payment on his ability to run during 20 hours during a year, when especially those hours are only determined at the end of a year.

So, while perhaps there can be statisticians arguing about whether it is 20 or 50 or 100 hours, ultimately this Commission and the California Public Utilities Commission will have to decide on contractual terms that determine how these facilities are paid. And we think that this is terribly important to make the bid analysis and ultimately the payments reflect both the operating conditions of the facilities, but their contribution to the system reliability.

That said, we think that an analysis that is more realistic toward the commercial terms that are likely to result will end up being important in this analysis. You could ultimately say one day is important, the day, the peak day. But there are few that would agree that their payments determined by their ability to run on that day, especially when that day isn't determined in advance.

So, we also believe, like everyone else, I think it was the comment from Dr. Kahn that you have to look at the way things are actually done.

And I think the way things are actually done contractually is that risk is important as well as operating characteristics. And the risk associated with starting a contract that is so tightly tied to a few hours would probably be unmanageable, and therefore we ought to be a little bit more flexible with regard to that, also.

That's all our comments, thanks.

PRESIDING MEMBER GEESMAN: Tom.

MR. TANTON: I would just like to reiterate the importance of connecting the analysis that is being discussed here with the contract terms. At the same time aggregating data results and whatnot for wind resources for a region or geothermal resources in Geysers or whatever also implies a contractual linkage which will not, in my view, ever occur.

Basically what it says is as a developer of a plant or a couple of plants in a region I am responsible and will be paid accordingly for the behavior and the performance of other resources in that same area.

Therefore, I strongly suggest not using

aggregated data in the bid evaluation process, or at least the final bid evaluation process. It can certainly be used for screening to figure out if there's a big enough difference in the bids.

If it comes down to bid differences that are smaller than the integration costs, you have to go on a case-by-case basis because it translates into contract and performance.

PRESIDING MEMBER GEESMAN: Other comments? Yeah.

MR. ALLEN: Gary Allen. I'd like to echo Tom's concerns, comments. What we're looking at in these analyses thus far is aggregated data. We don't contract with aggregate resources. We contract on a 50 or a 100 megawatt facility.

If we looked down at that level I strongly believe that the ELCC that we would see at that level would be substantially lower than the aggregate number.

PRESIDING MEMBER GEESMAN: Consistently?

MR. ALLEN: Consistently.

PRESIDING MEMBER GEESMAN: For every resource?

MR. ALLEN: I think for every resource,

but I think the differentials for the more baseloaded resources and the solar resources and non-intermittent resources are going to be trivial versus wind, which you will see a significant difference. Intuitive feel. I don't have any numbers to back that up.

PRESIDING MEMBER GEESMAN: Okay.

MR. ALLEN: Thank you.

PRESIDING MEMBER GEESMAN: Other comments? Don.

MR. SMITH: Well, I think the statement that an individual wind farm would have a lower ELCC than a bunch of wind farms taken as a group is incorrect. So I disagree with -- my intuition is different, based on looking at it. And regarding why it seems the group, their ELCC, and what ORA has and what the CEC's study group is different than the SCE study we just found out about which is kind of a bombshell and doesn't leave too much time to figure out how to respond to it.

But I suspect that the wind output per hour is the same in all cases, but the method of calculating the loss of load probability for each hour is different, involving, as it does, the hydroelectric situations. I'm disturbed about using them from a different year. But I'd have to learn more about what they did before I can, myself, comment intelligently. Not that that won't stop me from trying to say something by next Friday, at least about how we did it. And I'll try to find out how they did it. I'll try to initiate communication without too much hope of their being sufficient by that time.

But, overall I think it's great that we're having some -- I know it's boring a lot of the people here, but the issue of ELCC is something a few nerds find fascinating. And it's also quite relevant. And one thing that this process has led to is the whole discussion of this and other matters has moved to a completely different plane than it was a year or two ago.

So I'd like to compliment, if sometimes I say things that are critical, I'd like to compliment what the Energy Commission has done and its subcontractors. And that now at least we're dividing things up into different categories. You can have far more intelligent conversations than just vague feelings that somehow if something didn't come on when you wanted to turn it on it was worthless, which is the way it was a couple of years ago, at least from some participants' position.

But, anyway, I'll look forward to next Friday with trepidation and enthusiasm to see this new ELCC study.

MR. HAWKINS: I'd like to also make a comment on the issue of new units performance versus the aggregation.

The data that we're presenting here today is based upon units that were built in the last 10, 15, 20 years, which is what we saw as performance in 2002.

Looking at the new units that have been installed, the new wind generation units that are 1.5 megawatts, 1.8 megawatts, in the last three, four months, the new performance of those units in the Solano area, the outage rate on those things, their availability numbers are like 97 percent. Their breakage rate at this point is still a lot less. Their performance over much wider ranges of wind is much more spectacular than others. And in many cases we're seeing 50 percent production across the 4:00 peak in the afternoon.

So, therefore I would not draw the conclusion that looking at new wind resources or other types of renewable resources might, on a less aggregate basis, perform worse than what the aggregate numbers are.

PRESIDING MEMBER GEESMAN: I think you raise a good point, you know, in terms of the issues in front of both this Commission and the PUC. I just wonder the value of focusing on historical data when it's clear in several of these different resources we're going to be dealing with a completely new and different technology. And that indeed the RPS program is intended to elicit just such a new and different technology.

So, I'm very fascinated by the discussion today. I think that it does cast a lot of illumination on the subject. But, I'd caution everybody about investing too much emotion in what I characterize as false precision sometimes. The state moved pretty quickly to commit to a very large gas project a couple months ago with, I think, significantly less analysis and indisputably less transparency than this process. But we'll do the best we can and try and make everything that we rely upon subject to questioning and debate. And as much transparency as the different tariffs will allow us to.

Are there any other comments?

MR. TANTON: Procedural request. Getting somewhat up in age and forgetful a little bit, I wonder if it would be possible to have the transcript posted as early as possible so if there's anything that anybody said today that I forget I can address it in my comments next Friday?

PRESIDING MEMBER GEESMAN: I think we're usually about a week.

MR. TANTON: Well, I know. A week from today is the day the comments are due.

(Laughter.)

PRESIDING MEMBER GEESMAN: Yeah, so I don't think that's in the realm of possibility before submitting the comments.

MR. TANTON: Okay, thank you.

PRESIDING MEMBER GEESMAN: Sara? Oh, go

ahead, sir.

MR. MI: My name's Jingehao Mi from CDWR, California Department of Water Resources. Kind of have some questions. I read something, and also get involved in this issues. And we have some questions talk about, you know, the definition of renewable resources, you know, regarding the hydro. They said 30 megawatts or less is a renewable resources.

So, how about, you know, what is the reason for that?

PRESIDING MEMBER GEESMAN: State law.

MR. MI: Okay. And want to find that explanation, you know, where we can find that explanation in the documents.

PRESIDING MEMBER GEESMAN: SB-1078.

MR. MI: Oh, okay.

PRESIDING MEMBER GEESMAN: Passed in 2002.

MR. MI: Okay. Another thing is for the procedures how to some -- or something like what kind of procedures we have, should we, you know, who should we contact to --

PRESIDING MEMBER GEESMAN: Tim Tutt from

our renewable staff sitting in the back row.

MR. MI: Oh. Thank you very much.

PRESIDING MEMBER GEESMAN: Sara.

MS. MYERS: I was just going to ask another procedural request. If whether or not the slides from today, I know they're not the full Edison report, but whether or not they could be posted to the Energy Commission's website, you know, or Edison's website? I don't know. So that we could at least see those. I don't think they were a handout today.

PRESIDING MEMBER GEESMAN: I think we can do that. On our website? Anybody know?

UNIDENTIFIED SPEAKER: If they give them to us we can.

PRESIDING MEMBER GEESMAN: I think he gave them to us, didn't he?

UNIDENTIFIED SPEAKER: Not yet.

(Laughter.)

UNIDENTIFIED SPEAKER: The disk is in the computer.

(Laughter.)

PRESIDING MEMBER GEESMAN: Possession is nine-tenths of the law.

(Laughter.)

PRESIDING MEMBER GEESMAN: Is Ed in the room still?

DR. KAHN: Yes.

PRESIDING MEMBER GEESMAN: Can we get a copy that we could post to our website?

DR. KAHN: Yeah, I --

PRESIDING MEMBER GEESMAN: Okay.

DR. KAHN: We anticipated that. (inaudible).

PRESIDING MEMBER GEESMAN: Okay, good. Thank you.

MS. MYERS: I had one other comment. I certainly share your views regarding detail and precision. And actually I think this report by so many very capable people and institutions was a very detailed and precise report. And, again, CEERT appreciate the level of detail in this first phase, and again recognizes, like you, that we've got to get the RPS underway. It's been over, gosh, now it's been a year and a half since it was signed into law. And a first solicitation is very important. And I think this is certainly enough of a record to move that forward.

So, again, thank you for the hearing and your time to that end. Thank you.

PRESIDING MEMBER GEESMAN: Let me say, also, with respect to the subsequent phases of this report, we're updating our Integrated Energy Policy Report in 2004 to specifically address appropriate renewable goals for each utility. And I expect the integration issues raised by phase two and phase three of this report to be a critical element of that.

And we're committed in the 2005 IEPR to very carefully review the entire question of how best to integrate an increasing level of renewables, and in particular, intermittent, into the utility grid. And that is at the request of Gary Shunian from the Edison Company when we adopted the 2004 report.

So this is a subject that is going to receive a lot more attention going forward. And it's something that we're all going to have to learn together.

Sir.

MR. RUDNICK: Excuse me, I was late getting here today. Is there a fixed date for the first solicitation? Is that calendared?

PRESIDING MEMBER GEESMAN: The Energy Commission is committed to June of 2004. I have read in the trade press that the President of the Public Utilities Commission is committed to June of 2004. I'm not certain that the Governor's Office is satisfied with the progress that we're making on achieving that date.

So the answer is a soft, hoped for, mid-year target.

MR. RUDNICK: Thank you. And I'm still Phil Rudnick, by the way.

(Laughter.)

PRESIDING MEMBER GEESMAN: Thank you, Phil.

Other questions or comments?

Thank you very much. It's been a productive afternoon.

(Whereupon, at 3:40 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of June, 2004.